**DIRECT TESTIMONY**

**of**

**Mike Luth**
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Rates Department
Financial Analysis Division
Illinois Commerce Commission

Proposed General Increase in Gas Rates

**Mid American Energy Company**

**Docket No. 01-0696**

**March 1, 2002**

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Witness Identification

Q. Please state your name and business address.

A. Mike Luth, Illinois Commerce Commission ("Commission"), 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. What is your present position with the Commission?

A. I am currently a Rate Analyst in the Rates Department of the Financial Analysis Division. In that position, I review and analyze tariff filings by electric and gas utilities with regard to cost of service and rate design. I make recommendations to the Commission on such filings and participate in docketed proceedings as assigned. In this docket, I evaluated the cost of service and rate design aspects of the natural gas tariffs proposed by MidAmerican Energy Company ("MEC" or the "Company").

Q. Please state your professional qualifications and work experience.

A. I received a B.S. in Accounting from Illinois State University. I have earned the C.P.A and C.M.A professional designations. Since graduating, I have worked as an Assistant Property Manager with a real estate company and as a Field Auditor with the Wisconsin Department of Revenue. In October of 1990, I joined the Accounting Department of the Commission ("Commission"). In June 1998, I transferred from the Accounting Department of the Commission to the Rates Department.

Q. Have you testified in any previous Commission dockets?

A. Yes. I have testified on numerous occasions before the Commission.

Introduction to Testimony

Q. What is the subject matter of your testimony?

A. My testimony presents the results of my analysis of the cost of service study ("COSS") prepared by MEC witness Charles B. Rea and the rate design proposals of MEC witness Gregory C. Schaefer.

Q. Are you sponsoring any schedules as part of your testimony?

A. Yes, I am sponsoring the following schedules:

| | |
|---|---|
| Schedule 1 | Rate Design |
| Schedule 2 | Customer Class Allocation Factors |
| Schedule 3 | Peak Demand Estimation |
| Schedule 4 | Calculation of Load Factor |
| Schedule 5 | Functional Allocation Factors |

Summary of Findings

Q. Please summarize your findings.

A. My proposed rates begin with the COSS developed by Mr. Rea, adjusted for some differences in class and functional allocation factors. The differences in the class and functional allocation factors resulted in differences in the rates proposed by the Company and the rates that I've determined. The Company's proposals are also affected by the difference in Staff's recommended revenue requirement compared to the Company's proposed revenue requirement.

The most significant difference in rates is probably in the structure of Rates 70 and 85, which are available to commercial and industrial gas customers. Rate 70 and Rate 85 customers have the option of providing their own gas supply, thereby being referred to as transportation customers, or allowing the Company to supply them with gas, referred to as sales customers. The Company's proposed rates would charge the same distribution energy rate for Rate 70 customers, regardless of whether the customer is a sales customer or a transportation customer. Similarly, MEC would charge the same distribution energy charge for Rate 85 customers, again without distinction between sales and transportation customers. My proposed Rate 70 and Rate 85 rate structures differentiate between sales and transportation customers, charging less for the distribution energy charges for transportation customers compared to sales customers. Under my proposal, transportation customers are not charged for energy-related costs, but sales customers are, resulting in different rates for transportation customers and sales customers.

Class Allocation

Q. Why does your COSS have some class allocation factors that are different than in the COSS developed by MEC witness Rea?

A. Some of the class allocation factors in the COSS presented by Mr. Rea have significantly changed compared to similar allocation factors employed in the previous MEC gas rate case, Docket No. 99-0534, but the changes have not been adequately explained by the Company. Given that Docket No. 99-0534 occurred just over two years ago, the differences in allocation factors should be adequately explained or should change only to a small degree.

Weighted Services, Meters and Regulators

Q. Did you ask the Company about the differences in class allocation factors?

A. Yes, I did. In Staff data requests ML-13 through ML-15, I asked about the significant differences in the relative rate class weightings for services, meters and regulators. MEC replied that the calculations for the factors used by the Company in this docket are shown in the Company's testimony and in the reply to Staff data request ML-4. The Company's replies to Staff data requests ML-13 through ML-14 also state that the relative class weightings from Docket No. 99-0534 were provided by the Company's COSS consultant from that docket and are not available. I find the Company's inability to provide these materials problematic.

The Company's proposed weighting factors for Services, Meters and Regulators for Rate 60 were 1 in Docket No. 99-0534 and remain 1 in this docket. However, for the other customer classes, MEC has proposed fairly substantial changes in the weighting factors, as shown in the following table:

| | Rate 70 | Rate 85 | Rate 87 |
|---|---|---|---|
| Services | | | |
| Docket No. 99-0534 | 5 | 15 | 7.5 |
| MEC proposed, this docket | 1 | 2 | 1 |
| Percentage change | -80% | -87% | -87% |
| | | | |
| Meters | | | |
| Docket No. 99-0534 | 5 | 125 | 35 |
| MEC proposed, this docket | 7 | 60 | 8 |
| Percentage change | +40% | -52% | -77% |
| | | | |
| Regulators | | | |
| Docket No. 99-0534 | 5 | 125 | 35 |
| MEC proposed, this docket | 7 | 60 | 8 |
| Percentage change | +40% | -52% | -77% |

Rate 60 is excluded from the table because the weighting factors for these allocation factors remain at 1 in this docket, which is the same weighting as in Docket No. 99-0534.

Q. How did the MEC replies to Staff data requests ML-13 through ML-15 affect your conclusions concerning relative class weightings for services, meters and regulators?

A. Given that Docket No. 99-0534 occurred just over two years ago, that the relative class weightings for services, meters and regulators were found to be fair and reasonable in that docket; and that the number of gas customers in the test year in this docket has grown less than 1 percent, I think it is important that the proposed changes in these weightings be properly explained and justified. Based upon the Company's reply to Staff data requests ML-I3 through ML-15, a comparison of the relative class weightings proposed by MEC in this docket to the calculation of the relative class weightings in Docket No. 99-0534 cannot be made. Without a comparison to the allocation factors employed in Docket No. 99-0534, an explanation of the changes is not complete. As a result, I used the relative class weightings from Docket No. 99-0534 for services, meters and regulators. The Services, Meters and Regulators weighting factors are shown on Schedule 2, pages 1 and 2, items VI, VII, VIII and IX.

Q. How does a change in customer class weighting factors affect a COSS?

A. If the number of customers remains constant, an increased weighting factor increases the percentage of costs allocated to a given rate class, while a decrease in a weighting factor decreases the costs to a given rate class. For example, if two rate classes both have 20 customers, but a services weighting factor of 4 applies to one rate class and a services weighting factor of 1 applies to the other rate class, total weighted services is 100 (20 x 4 = 80, 20 x 1 = 20, 80 + 20 = 100). The rate class with a weighting factor of 4 will be allocated 80 percent (80 out of the total of100) of the services-related costs, while the other rate class will be allocated 20 percent of the services-related costs (20 out of the total of 100), despite having the same number of customers. In this docket, the considerable decreases in weightings for Rate 85 and 87 proposed by MEC have the effect of increasing the allocation of costs to Rate 60, and to a lesser degree, Rate 70.

Q. What class allocation factors in your COSS differ from those used by MEC witness Rea in his COSS?

A. In addition to the differences in the Services, Meters and Regulators customer class allocation factors, there is a difference in the Peak Demand allocation factors (items II and III on Schedule 2) and the Weighted Customers – Customer Service allocation factor (item X on Schedule 2).

Peak Demand Allocation Factor

Q. Why is there a difference in the Peak Demand allocation factors?

A. There are two Peak Demand allocation factors, one for the sales customers within each rate class, and one for the rate class as a whole. Although MEC witness Rea did not explain the calculation of the Company's proposed Peak Demand allocation factors, the Company's proposed Peak Demand allocation factors are based upon a projection applied to the system-design peak. The projection is calculated by determining the slope of the monthly sales to a given customer class compared to the monthly heating degree days, and determining an intercept value of monthly sales at zero heating degree days. The slope is multiplied by 90 which is the number of heating degree days assumed in the system-design peak. The product is then added to the intercept of monthly sales at zero heating degree days.

Mr. Rea's projection contradicts the system's actual peak demand and trends in consumption. One problem is that the MEC Illinois gas all-time peak is 1,143,026 therms in a day (Page 14 of attachment in reply to Staff data request ML-9), not the 1,193,551 therms calculated by Mr. Rea's projection (MEC Exhibit__(CBR-4)). Another problem is that Mr. Rea's projection results in Rate 60 having a peak demand of 21.6% more than the Rate 60 peak demand in Docket No. 99-0534, while the number of Rate 60 customers has grown by only 0.7%. Although the number of Rate 60 customers has grown, albeit by only 0.7%, weather-normalized Rate 60 sales are 4.6% lower, which suggests that peak day sales may also be lower. Total jurisdictional Illinois Gas peak demand is projected by Mr. Rea to be 14.7% higher than in Docket No. 99-0534, but the number of customers in all rate classes has grown by only 0.725%. Finally, the intercept or zero heating degree day Rate 60 load projected by Mr. Rea's COSS is 1,079,327 therms in an average month of zero heating degrees days. However, the months of July and August had zero heating degree days with Rate 60 sales of 1,277,596 therms and 1,310,290 therms respectively. The actual July and August zero heating degree day months averaged more than 19% greater therms of consumption by Rate 60 than the estimate for a zero heating degree month in Mr. Rea's COSS. With an understated intercept, the slope appears to be overstated for Rate 60, thereby overstating the effect of heating degree days when projecting peak sales.

Q. How did you determine Peak Demand allocation factors?

A. My Peak Demand allocation factors are based upon the peak demands approved by the Commission in Docket No. 99-0534, increased or decreased by the percentage of change in number of customers for each rate class. This is a reasonable approach, given that the billed Maximum Daily Requirement ("MDR") for Rate 85 stood at 88,500 therms in December 2000 (WP GCS-3b), and given the apparent trend of lower therms per Rate 60 customer discussed previously.

<u>Weighted Customers – Customer Service</u>

Q. How is the Weighted Customers – Customer Service allocation factor (Schedule 2, page 2, item X) different from the Weighted Customers – Services (Schedule 2, page 2, item VI) allocation factor?

A. These two factors allocate different costs. The Customer Service allocation factor allocates customer-related costs such as customer accounts expenses. The Services allocation factor allocates costs related to providing gas service to the customer's location, such as the pipe and related expenses from the distribution line to the customer's meter.

Q. Why is there a difference in the Weighted Customers – Customer Service allocation factor?

A. There are two reasons for the difference in the Weighted Customers – Customer Service allocation factor. The first reason is that Mr. Rea rounded the class weights to whole numbers, rather than two decimal points. Given the magnitude of allocating $3.8 million in customer service costs to 65,319 customers, it is appropriate to weight the classes to a greater level of detail resulting from a rounding to two decimal points. For example, a rounding of a customer weight from 2.49 down to 2 would reduce the weighting of the customer class by nearly 20 percent. Moreover, with the use of personal computers, it is not difficult to weight the customer classes to two decimal points.

The other reason for the difference in the Weighted Customers – Customer Service allocation factor is that the Company allocated marketing costs to the customer classes according to margins. In contrast, I allocated marketing costs according to throughput because the classes with the larger volumes subject to transportation represent the classes with the largest potential market for MEC to be the supplier of gas. This difference resulted in heavier class weightings for Rates 85 and 87, with some reduction in the class weight for Rate 70. The difference in class weightings for marketing should not be considered drastic, however, because Rate 70 is allocated 70% of marketing costs under my approach, compared to 85% under the MEC approach. Weighting marketing costs on the basis of throughput is also appropriate because, as MEC witness Schaefer has stated (Direct Testimony of Gregory C. Schaefer, page 8, lines 198 through 200), Rate 70 has a wide range of customers who do not consume large volumes of natural gas and are thus less likely to be attractive to potential supply competitors. More than 90% of Rate 70 customers are billed for total monthly gas volumes within the first block of Rate 70, which is 1,000 therms or less in a month (MEC WP GCS-3c, pages 4, 6, 10 and 12). By comparison, Rate 85 customers consumed an average of 181,652 therms per month and Rate 87 customers consumed an average of 17,857 therms per month.

Functional Allocation

Q. What is the difference between a functional allocation factor and customer class allocation factor?

A. A functional allocation factor allocates costs recorded in the Company's accounts by the type of costs in those accounts. Functions are shown in the items listed under the sub-headings on page 5 of my Schedule 1. After the costs for each account have been allocated according to function, the costs in each function are totaled. The total costs for each function are then allocated to the customer classes using customer class allocation factors shown in the right-hand column on page 5 of my Schedule 1. The customer class allocation factors are detailed on my Schedule 2.

Q. Are there any differences in the functional allocation of any accounts between the Company's COSS and your COSS?

A. Yes, there are a few differences. I allocated account 923 – Outside Services according to payroll, instead of supervised operating and maintenance expense ("O & M"). I allocated account 925 – Injuries and Damages by weighting field distribution payroll by a factor of 90%, and office payroll (accounts 901-935) by the remaining 10%. Finally, I allocated account 931 – Rents by the combination of customer service, accounting, sales and administrative and general ("A & G") expenses, rather than supervised O & M.

Q. Why have you allocated account 923 – Outside Services by function according to payroll, instead of supervised operating and maintenance expense?

A. This is an A & G account that records the costs for professional consultants and others that are not directly chargeable to other functions. The account can be considered a payroll account because it involves the payment for services rendered by people who might be employed by the Company if the Company had sufficient recurring need for the people with the skills needed on a temporary or intermittent basis. Since the costs in the account cannot be directly charged to other functions, and represent payments for the services of people outside the Company's payroll, it is reasonable to allocate the costs by function according to the payroll of each function.

Q. Why have you weighted payroll heavily toward field distribution in allocating account 925 – Injuries and Damages by function?

A. This account records costs associated with claims against the Company for Injuries and Damages to the Company's employees, people outside of the Company, or to the property of others. It also records the cost of insurance for claims of employees or others resulting from the Company's activities. It is reasonable to expect that activities related to operating and maintaining gas distribution equipment in the field are considerably more risky than activities related to MEC employees involved in office activities such as customer accounts and A & G, so a heavier weighting should be given to distribution payroll compared to office payroll.

Q. Why have you allocated account 931 – Rents by function according to customer service, accounts, sales, and A & G expenses rather than supervised O & M?

A. Costs recorded in this account represent costs for the property of others used, occupied or operated in connection with customer accounts, customer service and informational, sales and A & G functions of the utility. The Company's supervised O & M functional allocation factor includes distribution-related costs. Rents for distribution-related property should be recorded in Rent accounts directly chargeable to distribution, such as accounts 860 and 881. My allocation factor reflects the division of customer and A & G costs according to function, and applies the costs of equipment rented to assist in customer and A & G activities according to how the MEC functions are served by customer and A & G activities.

Rate Design

Q. What is the effect of your COSS on rates?

A. A table of my proposed rates for MEC natural gas service is shown on page 1 of Schedule 1. Each rate class has a proposed monthly customer service charge and a distribution energy charge per therm of consumption. Rates 70, 85 and 87 have a proposed monthly transportation administrative charge ("TAC"), applicable only to transportation customers. Rate 85 has a distribution demand charge per therm of MDR.

Q. In general, what types of costs are recovered from the different charges?

A. A customer charge recovers customer-related costs that theoretically do not vary with consumption or demand. A distribution energy charge recovers costs associated with average use of the system, and for sales customers, costs of securing gas supply. If a rate class is not demand-metered, which is the case with Rates 60, 70 and 87, the distribution energy charge also recovers peak demand-related costs theoretically caused by the use of the system on the maximum day of gas delivery. A distribution demand charge recovers peak demand-related costs if the rate class is metered for demand, which for MEC, is Rate 85 only. A TAC recovers customer costs caused by transportation customers and is therefore not applicable to sales customers.

Rate 60

Q. What are your proposals for Rate 60?

A. My proposals for Rate 60 are based upon my COSS, Staff's recommended revenue requirement and current rates. The structure of my proposed Rate 60 is similar to MEC's proposal for Rate 60 in that I am proposing a monthly customer charge and a distribution energy charge per therm consumed. Although my proposed structure of Rate 60 is the same as MEC's, the charges are different. The difference in amounts is the result of the difference in my COSS results and the difference in the Staff recommended revenue requirement.

My COSS indicates that Rate 60 would have a lower distribution energy charge than what is presently charged, and a higher customer charge than what is presently charged, although lower than what MEC is proposing. My proposed rates adjust the situation of an increased customer charge combined with a lower distribution energy charge by maintaining the distribution energy charge at the current rate per therm consumed, while increasing the monthly customer charge by less than the amount indicated by the COSS. This approach recovers costs from the Rate 60 customer class at approximately the overall class revenue requirement, and attempts to maintain a continuity of charges in Rate 60.

Rate 70

Q. What are your proposals for Rate 70?

A. My proposals for Rate 70 are based upon my COSS, Staff's recommended revenue requirement and current rates. The structure of my proposed Rate 70 is similar to MEC's proposal for Rate 70 in that I am proposing a monthly customer charge, a monthly TAC if applicable, and a distribution energy charge per therm consumed. The structure of my proposed Rate 70 is different, however, in that the amounts for the proposed charges are different with a distinction between sales and transportation customers. I am also proposing to maintain the current declining block structure for the distribution energy charge per therm, compared to MEC's proposal, which has the same charge for the first two usage blocks in Rate 70 followed by a decline in the highest consumption block.

Q. How does your proposed Rate 70 customer charge differ from the customer charge proposed by MEC?

A. MEC is proposing that the Rate 70 customer charge be the same as the customer charge for Rate 60. I am proposing that the customer charge be set at $25.00 per month, which is substantially less than the amount indicated by the COSS, but considerably closer to the COSS than the $12.00 proposed by MEC. The MEC proposal would result in a small decrease in the Rate 70 monthly customer charge, with the customer charge set considerably lower than indicated by the COSS. MEC made this proposal to reflect the wide range of small natural gas consumers under Rate 70. I agree that smaller Rate 70 customers should be considered in determining a monthly customer charge, but at the same time, an understated customer charge creates a problem of under-recovered customer costs. With an understated customer charge, customer-related costs need to be recovered through the Rate 70 distribution energy charge. MEC proposes to recover the remaining customer-related costs through the first two consumption blocks of Rate 70, which are 0 to 1,000 therms per month and 1,001 to 10,000 therms per month. I agree with this proposal also. However, constraining the customer charge to less than one-third of the rate indicated by the COSS results in the first two blocks of the distribution energy charge being disproportionately higher than the charges are now.

My COSS indicates that the Rate 70 customer charge should be approximately $45 per month or more. In order to consider small Rate 70 customers, while moving the customer charge closer to the Rate 70 COSS result, I propose that the customer charge be $25.00. While this is higher than my proposed Rate 60 residential customer charge, it is still not excessive for a commercial customer. This increase in the customer charge also reduces the impact of unrecovered customer-related costs on the first two blocks of the distribution energy charge, so that the increase in the distribution energy charge is not as considerable as it would have been had the customer charge been set at the Rate 60 level. Furthermore, the increase in the customer charge will be offset for the small Rate 70 customer through a lower distribution energy rate per therm consumed and billed in the first two blocks of Rate 70.

Q. How does your TAC differ from the amount proposed by MEC?

A. My proposed TAC is higher than the $75 proposed by MEC as a result of the differences between my COSS and the MEC COSS. The increase is offset to some degree by the elimination of the Transportation Metering Charge.

Q. How do your proposed Distribution Energy charges differ from those proposed by MEC?

A. My proposed rates are higher for sales customers compared to transportation customers, and maintain a declining block structure through the first two Rate 70 consumption blocks for both sales and transportation customers. MEC proposes that the distribution energy charge be the same for transportation customers and sales customers, and that the same rate per therm be charged through the first two consumption blocks.

The differences in my proposed rates for sales customers compared to transportation customers result from eliminating energy-related costs from transportation rates. Since transportation customers arrange their own supplies of gas, it is not appropriate to charge them for gas supply expenses incurred by MEC. Page 4 of my Schedule 1 develops an energy costs factor per therm for sales customers, which is included in the block charges for sales customers but not transportation customers. Both the sales and the transportation distribution energy rates recover demand-related costs.

I am maintaining a declining structure for the first two blocks of the Rate 70 distribution energy charges so that more of the customer-related costs are recovered per therm in the first consumption block compared to the second consumption block. Since customer-related costs do not theoretically vary with consumption, it is appropriate the customer-related costs not recovered by the understated Rate 70 customer charge be more quickly recovered in the first consumption block under my proposed declining block structure.

Rate 85

Q. What are your proposals for Rate 85?

A. Like MEC, I am proposing a monthly customer charge, a monthly TAC if applicable, a distribution demand charge and a distribution energy charge. Unlike MEC, my proposed distribution demand and energy charges are lower for transportation customers compared to sales customers.

Q. How are your monthly customer and TAC's different from the MEC proposals for these charges?

A. My proposed monthly customer and transportation administrative charges are higher than the similar Rate 85 amounts proposed by MEC. The differences are primarily the result of differences in my COSS compared to the Company's COSS.

Q. How are your monthly distribution demand and distribution energy charges different from the comparable MEC proposals?

A. My proposed distribution demand rates are lower than the MEC proposed rates. The sales distribution demand rate is somewhat higher than the transportation distribution demand rate because an adjustment is made to the transportation rate so that costs over-recovered through the TAC are offset through the adjustment to the transportation distribution demand charge. Peak demand-related costs are recovered through my proposed distribution demand charge divided by MDR therms for Rate 85.

My proposed distribution energy rates are higher than the MEC proposed rates. The ratio of average demand-related costs to peak demand related costs is higher under my COSS than the ratio used in MEC witness Rea's COSS. Mr. Rea calculates the ratio based upon the system design peak of 1,513,380 therms (MEC Exhibit__(CBR-3). My review indicates that the system's all-time peak of 1,143,026 therms was set in February 1996 (page 14 of attachment to reply to Staff data request ML-9), so the system design peak appears to be irrelevant at this time in determining how peak demand-related costs are affected by the current use of the system. The system design peak is 32% higher than the all-time peak set six years ago. I have based the ratio of average demand-related costs to peak demand-related costs upon the all-time system peak, rather than the system design peak, so average demand-related costs in my COSS are higher than in the MEC COSS. Although it is not clear whether Rate 85 average demand-related costs are recovered through the distribution energy charge proposed by MEC witness Schaefer, a difference in the ratio of average demand-related costs to peak demand-related costs would be a reason why my proposed distribution demand charge for Rate 85 is lower than the proposal by MEC, and why my proposed distribution energy charge is higher than the proposal by MEC.

The distribution energy charge that I am proposing for Rate 85 transportation customers is less than the comparable charge for Rate 85 sales customers. As with Rate 70, I am proposing to recover energy-related costs through the charge to sales customers only because transportation customers arrange for their own gas supply. Transportation customers should therefore not be charged for gas supply costs incurred by MEC, which I accomplish through a lower proposed distribution energy charge for Rate 85 transportation customers compared to the Rate 85 sales customers.

Rate 87

Q. What are your proposals for Rate 87?

A. My proposed structure of Rate 87 is the same as that for the Company, in that I am proposing a monthly customer charge, a monthly TAC and a distribution energy charge per therm consumed. As with Rates 60, 70, and 85, the amounts that I am proposing for each charge are different from the amounts proposed by MEC. The differences are primarily caused by the difference in the results of my COSS compared to the MEC COSS.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MidAmerican Energy Company
Rate Design - Summary of Proposed Rates

| | Customer Charge per month | Transportation Administrative Charge per month | Distribution Energy Charge per therm -- Sales | Distribution Energy Charge per therm -- Transportation | Distribution Demand Charge per therm MDR -- Sales | Distribution Demand Charge per therm MDR -- Transportation |
|---|---|---|---|---|---|---|
| Rate 60 | $ 10.30 | | $ 0.08051 | ----- | ----- | ----- |
| Rate 70 | $ 25.00 | $ 114.00 | | | | |
| 0 - 1,000 | | | $ 0.11542 | $ 0.10346 | ----- | ----- |
| 1,001 - 10,000 | | | $ 0.10281 | $ 0.09085 | ----- | ----- |
| 10,000 + | | | $ 0.06495 | $ 0.05299 | ----- | ----- |
| Rate 85 | $ 1,738.00 | $ 114.00 | $ 0.03074 | $ 0.02485 | $ 0.20287 | 0.20259 |
| Rate 87 | $ 318.00 | $ 114.00 | $ 0.04265 | $ 0.03631 | ----- | ----- |

Distribution Energy Charge for Rate 87 Transportation is the Sales Distribution Energy Charge
discounted by Energy Costs per therm. $1,746 divided by 275,696 therms billing units discount.

Mid-American Energy Company
Rate Design

| | Net COS | Rate 60 | Rate 70 | Rate 85 | Rate 87 |
|---|---|---|---|---|---|
| Customer Costs: | $ 11,759,027 | $ 8,642,307 | $ 2,927,043 | $ 182,828 | $ 6,848 |
| Multiplied by: Staff Revenue Adjustment Factor (see page 6) | 0.97563 | 0.97563 | 0.97563 | 0.97563 | 0.97563 |
| | $ 11,472,407 | $ 8,431,655 | $ 2,855,698 | $ 178,372 | $ 6,681 |
| Less: Over-recovered Demand and Energy Costs (Rate 60 only) | $ (1,014,790) | $ (1,014,790) | | | |
| Less: Over-recovered Rate 60 Customer Costs | | | | $ (20,178) | |
| Net Customer Costs | $ 10,457,616 | $ 7,416,865 | $ 2,855,698 | $ 158,194 | $ 6,681 |
| Divided by: Total Monthly bills | | 722,043 | 61,663 | 91 | 21 |
| **Monthly Customer Charge** | | **$ 10.30** | **$ 25.00** | **$ 1,738.00** | **$ 318.00** |
| Multiplied by: Total Monthly bills | | 722,043 | 61,663 | 91 | 21 |
| Revenue Recovery | $ 9,143,454 | $ 7,437,043 | $ 1,541,575 | $ 158,158 | $ 6,678 |
| Over/(under) recovery | $ (1,314,162) | $ 20,178 | $ (1,314,123) | $ (20,214) | $ (3) |
| Transportation Administration Costs: | $ 107,202 | $ - | $ 97,456 | $ 9,746 | $ - |
| Multiplied by: Staff Revenue Adjustment Factor (see page 6) | 0.97563 | - | 0.97563 | 0.97563 | - |
| | $ 104,589 | $ - | $ 95,081 | $ 9,508 | $ - |
| Divided by: Total Monthly bills | | | 834 | 86 | |
| **Monthly Transportation Administration Charge** | | | **$ 114.00** | **$ 114.00** | |
| Multiplied by: Total Monthly bills | | | 834 | 86 | |
| Revenue Recovery | $ 104,880 | | $ 95,076 | $ 9,804 | |
| Over/(under) recovery | $ 291 | $ - | $ (5) | $ 296 | $ - |
| Demand Costs: | $ 6,091,474 | $ 3,294,032 | $ 2,140,348 | $ 646,835 | $ 10,258 |
| Multiplied by: Staff Revenue Adjustment Factor (see page 6) | 0.97563 | 0.97563 | 0.97563 | 0.97563 | 0.97563 |
| | $ 5,942,997 | $ 3,213,742 | $ 2,088,178 | $ 631,069 | $ 10,008 |
| Distribution Demand Charge per MDR therm (Rate 85 only) | | | | see page 4 | |
| Revenue Recovery | $ 220,020 | | | $ 220,020 | |
| Over/(under) recovery | $ (5,722,977) | $ (3,213,742) | $ (2,088,178) | $ (411,049) | $ (10,008) |

Mid-American Energy Company
Rate Design

| | Net COS | Rate 60 | Rate 70 | Rate 85 | Rate 87 |
|---|---|---|---|---|---|
| Energy Costs: | $ 998,284 | $ 669,736 | $ 322,410 | $ 4,348 | $ 1,790 |
| Multiplied by: Staff Revenue Adjustment Factor (see page 6) | 0.97563 | 0.97563 | 0.97563 | 0.97563 | 0.97563 |
| | $ 973,951 | $ 653,412 | $ 314,551 | $ 4,242 | $ 1,746 |
| Plus or (minus) under-recovered/(over)-recovered Customer Costs | 1,314,162 | | 1,314,123 | 20,214 | 3 |
| Plus or (minus) under-recovered/(over)-recovered Transportation Administration Costs | (291) | - | 5 | (296) | - |
| Plus or (minus) under-recovered/(over)-recovered Demand Costs | 5,722,977 | 3,213,742 | 2,088,178 | 411,049 | 10,008 |
| | $ 8,010,800 | $ 3,867,154 | $ 3,716,857 | $ 435,209 | $ 11,758 |
| Divided by: Total Billing units (therms) | | 60,637,738 | | | 275,696 |
| Distribution Energy Charge per therm | | **$ 0.08051** | **see page 3** | **see page 4** | **0.04265** |
| Multiplied by: Total Billing units | | $ 60,637,738 | | | $ 275,696 |
| Revenue Recovery | $ 9,025,390 | $ 4,881,944 | $ 3,716,664 | $ 415,024 | $ 11,758 |
| Over/(under)-recovery | $ 1,014,590 | $ 1,014,790 | $ (193) | $ (20,185) | $ 0 |
| Total Revenue Recovery | $ 18,493,744 | $ 12,318,987 | $ 5,353,315 | $ 803,006 | $ 18,436 |
| Total Unadjusted Costs (see page 6) | 18,955,986 | 12,606,075 | 5,487,257 | 843,757 | 18,897 |
| Multiplied by: Staff Revenue Conversion Factor (see page 6) | 0.97563 | 0.97563 | 0.97563 | 0.97563 | 0.97563 |
| Net Revenues from Base Rates | 18,493,944 | 12,298,809 | 5,353,508 | 823,191 | 18,436 |
| Over/(under)-recovery | $ (200) | $ 20,178 | $ (193) | $ (20,185) | $ 0 |

MidAmerican Energy Company
Rate 70 Distribution Energy Charges

| | Total | Sales | Transportation | |
|---|---|---|---|---|
| Energy Costs x Staff Revenue Conversion Factor | $ 314,551 | $ 314,551 | | |
| Demand Costs: | | | | |
| Average x Staff Revenue Conversion Factor | 979,128 | 658,854 | $ 320,274 | Throughput |
| Peaking x Staff Rev. Conversion Factor | 1,109,050 | 859,731 | 249,320 | Peak |
| Plus or (minus) under/(over)- recovered customer costs | 1,314,123 | 1,296,463 | 17,660 | Customers |
| Plus or (minus) under/(over)- recovered transportation administration costs | | | 5 | |
| | $ 3,716,853 | $ 3,129,599 | $ 587,258 | |
| Divided by: Throughput | 39,404,125 | 26,290,065 | 13,114,060 | GCS-1, Schedule 2, page 1 |
| Average per therm | 0.09433 | 0.11904 | 0.04478 | |
| Average Energy Costs per therm | 0.00798 | 0.01196 | | |
| Average Demand Costs per therm | 0.05299 | $ 0.05776 | $ 0.04343 | |
| Average Unrecovered Customer Costs per therm | $ 0.04454 | $ 0.05415 | $ 0.00322 | First 2 blocks, GCS-3, page 1 |

| Block Charges per therm: | Sales | Transportation | |
|---|---|---|---|
| **0-1,000** | | | |
| Customer Costs per therm + Block Increase | $ 0.05047 | $ 0.05047 | |
| Plus: Demand Costs per therm | 0.05299 | 0.05299 | |
| Plus: Energy Costs per therm | 0.01196 | | |
| | **0.11542** | **0.10346** | |
| Multiplied by: Billing units (therms) | 14,859,979 | 774,706 | WP GCS-3a |
| Revenue Recovery | $ 1,715,139 | $ 80,151 | |
| **1,001-10,000** | | | |
| Customer Costs per therm x .85 | $ 0.03786 | $ 0.03786 | |
| Plus: Demand Costs per therm | 0.05299 | 0.05299 | |
| Plus: Energy Costs per therm | 0.01196 | | |
| Distribution Energy Rate per therm | **0.10281** | **0.09085** | |
| Multiplied by: Billing units (therms) | 9,163,856 | 4,706,391 | WP GCS-3a |
| Revenue Recovery | $ 942,136 | $ 427,576 | |
| **10,001+** | | | |
| Demand Costs per therm | 0.05299 | 0.05299 | |
| Energy Costs per therm | 0.01196 | | |
| Distribution Energy Rate per therm | **0.06495** | **0.05299** | |
| Multiplied by: Billing units (therms) | 2,266,230 | 7,632,962 | WP GCS-3a |
| Revenue Recovery | $ 147,192 | $ 404,471 | |
| Total Revenue Recovery | $ 2,804,467 | $ 912,197 | $ 3,716,664 |

Rate 85 Distribution Demand and Energy Charges

| | Total | Sales | Transportation | |
|---|---|---|---|---|
| Energy Costs x Staff Revenue Conversion Factor | $ 4,242 | $ 4,242 | | |
| Divided by: Billing units (therms) | | 720,595 | | |
| Energy Costs per billing unit | | $ 0.00589 | | |
| Demand Costs: | | | | |
| Average x Staff Revenue Conversion Factor | 410,753 | 17,906 | 392,847 | Throughput |
| Peaking x Staff Rev. Conversion Factor | 220,316 | 11,319 | 208,997 | Peak |
| Plus or (minus) under/(over)-recovered transportation administration costs | (296) | | (296) | |
| | $ 635,015 | $ 754,062 | $ 601,548 | |

Demand Charge per Maximum Daily Requirement ("MDR"):

| | Total | Sales | Transportation | |
|---|---|---|---|---|
| Peaking Demand Costs | $ 220,316 | | | |
| Less: Over-recovered Transportation Adm. Costs | | | (296) | |
| Divided by: Demand billing units (MDR therms) | 1,086,000 | | 1,059,000 | |
| Cost/(credit) per MDR therm | $ 0.20287 | | (0.00028) | |
| **Distribution Demand Charge per MDR therm** | | **$ 0.20287** | **$ 0.20259** | |
| Multiplied by: Demand Billing Units | | 27,000 | 1,059,000 | WP GCS-3b |
| Revenue Recovery | | $ 5,477 | $ 214,543 | $ 220,020 |

Energy Charge per therm:

| | Total | Sales | Transportation | |
|---|---|---|---|---|
| Average Demand Costs | $ 410,753 | | | |
| Divided by: Energy Billing units (therms) | 16,530,375 | | | |
| | $ 0.02485 | | | |
| Plus: Energy Costs per therm | | $ 0.00589 | | |
| **Distribution Energy Charge per therm** | | **$ 0.03074** | **$ 0.02485** | |
| Multiplied by: Energy Billing Units | | 720,595 | 15,809,780 | |
| Revenue Recovery | | $ 22,151 | $ 392,873 | $ 415,024 |
| | | | | $ 635,044 |

Mid-American Energy Company
Rate Design - Summary of Costs by Function and
Staff Revenue Conversion Factor

| Functional Costs | Net COS | Rate 60 | Rate 70 | Rate 85 | Rate 87 | Allocation Method |
|---|---|---|---|---|---|---|
| Demand-related Costs | | | | | | |
| Mains (Average) | 2,978,548 | 1,544,392 | 1,003,590 | 421,015 | 9,551 | Throughput (Weather Normalized) |
| Mains (Peaking) | 3,112,926 | 1,749,640 | 1,136,758 | 225,820 | 707 | Peak Demand (Total Throughput) |
| | $ 6,091,474 | $ 3,294,032 | $ 2,140,348 | $ 646,835 | $ 10,258 | |
| Customer-related Costs | | | | | | |
| Services | $ 3,738,485 | $ 2,615,636 | $ 1,116,981 | $ 5,216 | $ 652 | Weighted Customers - Services |
| Meters | 3,748,053 | 2,594,126 | 1,107,796 | 43,113 | 3,018 | Weighted Customers - Meters |
| Regulators | 465,273 | 322,028 | 137,519 | 5,352 | 375 | Weighted Customers - Regulators |
| Industrial Meters | 15,262 | - | 4,869 | 10,392 | - | Weighted Customers - Industrial Meters |
| Customer Accounts | 3,791,953 | 3,110,517 | 559,878 | 118,755 | 2,804 | Weighted Customers - Cust Service |
| | $ 11,759,027 | $ 8,642,307 | $ 2,927,043 | $ 182,828 | $ 6,848 | |
| Transportation Administration | $ 107,202 | - | $ 97,456 | $ 9,746 | - | Transport Customers |
| Energy Costs | | | | | | |
| Cost of Gas | $ 48,872,160 | $ 33,598,844 | $ 14,759,275 | $ 273,169 | $ 240,872 | Cost of Gas (Direct Assigned) |
| Less: PGA Recoveries | (48,535,381) | (33,367,313) | (14,657,568) | (271,287) | (239,213) | |
| | $ 336,779 | $ 231,530 | $ 101,706 | $ 1,882 | $ 1,660 | |
| Peak Facilities | 661,505 | 438,206 | 220,703 | 2,465 | 130 | Peak Demand (Sales Service Only) |
| | $ 998,284 | $ 669,736 | $ 322,410 | $ 4,348 | $ 1,790 | |
| Total Costs (unadjusted to Staff) | $ 18,955,986 | $ 12,606,075 | $ 5,487,257 | $ 843,757 | $ 18,897 | |

| | | |
|---|---|---|
| Staff Revenue Requirement | $ 19,008,000 | |
| Less: Other Operating Revenues | (514,056) | |
| Net Revenue from Base Rates | $ 18,493,944 | same as page 3, Total Costs adjusted by Staff Revenue Conversion Factor |
| Divided by: ML Cost Study Revenue Requirement (unadjusted) | 18,955,986 | |
| **Staff Revenue Conversion Factor** | **0.97563** | used in calculating charges on pages 2 and 3 |

# MidAmerican Energy Company
## Customer Class Allocators

### I. Throughput (Weather Normalized)

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| W.N. Throughput | 60,637,738 | 39,404,125 | 16,530,375 | 374,989 | 116,947,227 |
| **Allocator** | **0.5185051** | **0.3369394** | **0.1413490** | **0.0032065** | **1.0000000** |

### II. Peak Demand (Sales Service Only)

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| **Allocator** | **0.6624379** | **0.3336381** | **0.0037271** | **0.0001969** | **1.0000000** |

### III. Peak Demand (Total Throughput)

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| **Allocator** | **0.5620564** | **0.3651736** | **0.0725428** | **0.0002272** | **1.0000000** |

### IV. Customers

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | 60,170 | 5,139 | 8 | 2 | 65,319 |
| **Allocator** | **0.9211715** | **0.0786754** | **0.0001225** | **0.0000306** | **1.0000000** |

### V. Transport Customers

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | - | 70 | 7 | - | 77 |
| **Allocator** | **-** | **0.9090909** | **0.0909091** | **-** | **1.0000000** |

### VI. Weighted Customers - Services

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | 60,170 | 5,139 | 8 | 2 | 65,319 |
| Weight | 1.00 | 5.00 | 15.00 | 7.50 | N/A |
| Weighted Customers | 60,170 | 25,695 | 120 | 15 | 86,000 |
| **Allocator** | **0.6996512** | **0.2987791** | **0.0013953** | **0.0001744** | **1.0000000** |

MidAmerican Energy Company
Customer Class Allocators

## VII. Weighted Customers - Meters

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | 60,170 | 5,139 | 8 | 2 | 65,319 |
| Weight | 1.00 | 5.00 | 125.00 | 35.00 | N/A |
| Weighted Customers | 60,170 | 25,695 | 1,000 | 70 | 86,935 |
| **Allocator** | **0.6921263** | **0.2955657** | **0.0115028** | **0.0008052** | **1.0000000** |

## VIII. Weighted Customers - Regulators

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | 60,170 | 5,139 | 8 | 2 | 65,319 |
| Weight | 1.00 | 5.00 | 125.00 | 35.00 | N/A |
| Weighted Customers | 60,170 | 25,695 | 1,000 | 70 | 86,935 |
| **Allocator** | **0.6921263** | **0.2955657** | **0.0115028** | **0.0008052** | **1.0000000** |

## IX. Weighted Customers - Industrial Meters

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Eligible Customers | - | 82 | 7 | - | 89 |
| Weight | 1.00 | 5.00 | 125.00 | 35.00 | N/A |
| Weighted Customers | - | 410 | 875 | - | 1,285 |
| **Allocator** | **-** | **0.3190661** | **0.6809339** | **-** | **1.0000000** |

## X. Weighted Customers - Customer Service - see page 4

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Total Customers | 60,170 | 5,139 | 8 | 2 | 65,319 |
| Weight | 1.00 | 2.11 | 287.15 | 27.12 | N/A |
| Weighted Customers | 60,170 | 10,830 | 2,297 | 54 | 73,352 |
| **Allocator** | **0.8202941** | **0.1476490** | **0.0313175** | **0.0007394** | **1.0000000** |

MidAmerican Energy Company
Customer Class Allocators

## XI. Manufactured Gas Cleanup

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Throughput | 60,637,738 | 39,404,125 | 16,530,375 | 374,989 | |
| Revenue | 44,518,635 | 19,066,105 | 995,271 | 258,240 | |
| COG | 33,367,314 | 14,657,569 | 271,287 | 239,213 | |
| Total Margin | $ 11,151,321 | $ 4,408,536 | $ 723,984 | $ 19,027 | $ 16,302,869 |
| Margin Allocator | 0.6840097 | 0.2704148 | 0.0444084 | 0.0011671 | 1.0000000 |
| Throughput Allocator | 0.5185051 | 0.3369394 | 0.1413490 | 0.0032065 | 1.0000000 |
| **50/50** | **0.6012574** | **0.3036771** | **0.0928787** | **0.0021868** | **1.0000000** |

## XII. Cost of Gas

| | 60 | 70 | 85 | 87 | Total (w/o Contract) |
|---|---|---|---|---|---|
| Cost of Gas | $ 33,367,314 | $ 14,657,569 | $ 271,287 | $ 239,213 | $ 48,535,382 |
| **Allocator** | **0.6874843** | **0.3019976** | **0.0055895** | **0.0049286** | **1.0000000** |

# MidAmerican Energy Company
## Peak Demand Estimation

(therms)

| Month | Rate 60 | Rate 70 | Rate 85 | Rate 87 | HDD | 70 Sales |
|---|---|---|---|---|---|---|
| Jan | 11,064,039 | 6,797,249 | 2,070,360 | 17,643 | 1,268 | 5,192,340 |
| Feb | 8,046,801 | 5,835,260 | 2,193,481 | - | 863 | 3,899,068 |
| Mar | 5,658,784 | 3,930,449 | 1,891,382 | 11,526 | 606 | 2,443,622 |
| Apr | 3,902,283 | 2,797,673 | 1,584,144 | 5,970 | 427 | 1,645,074 |
| May | 2,149,331 | 1,860,978 | 1,479,846 | 4,513 | 112 | 804,427 |
| Jun | 1,279,506 | 1,025,347 | 1,205,653 | 85,056 | 29 | 459,395 |
| Jul | 1,277,596 | 1,235,596 | 1,146,228 | 59,636 | - | 598,508 |
| Aug | 1,310,290 | 874,376 | 810,512 | 25,441 | - | 399,132 |
| Sep | 1,464,309 | 1,509,052 | 808,773 | 41,720 | 97 | 637,184 |
| Oct | 2,733,971 | 1,906,646 | 730,429 | 29,087 | 263 | 1,073,422 |
| Nov | 7,639,933 | 3,897,112 | 931,094 | 54,855 | 866 | 3,092,289 |
| Dec | 12,803,430 | 6,992,428 | 1,678,470 | 39,542 | 1,601 | 5,303,646 |
| | | | | | | |
| Intercept | 1,079,327 | 1,139,964 | 1,078,289 | 36,761 | | 407,296 |
| Slope | 7,563 | 4,074 | 586 | (11) | | 3,369 |
| | | | | | | |
| Estimated Annual Sales | 61,478,259 | 39,819,222 | 16,696,686 | 371,926 | | 26,504,989 |
| Average Load | 167,973 | 108,796 | 45,619 | 1,016 | | 72,418 |
| Estimated Peak Day | 716,088 | 404,048 | 88,058 | 235 | | 316,591 |
| Estimated Load Factor | 23.46% | 26.93% | 51.81% | 433.33% | | 22.87% |
| | | | | | | |
| W.N. Total Throughput | 60,637,738 | 39,404,125 | 16,530,375 | 374,989 | | |
| W.N. Peak Demand | 584,821 | 379,964 | 75,481 | 236 | 1,040,502 | |
| Allocator | 0.56206 | 0.36517 | 0.07254 | 0.00023 | 1.00000 | |
| | | | | | | |
| W.N. Total Sales | 60,637,738 | 26,215,078 | 720,595 | 275,696 | | |
| W.N. Peak Demand | 584,821 | 294,546 | 3,290 | 174 | 882,831 | |
| Allocator | 0.66244 | 0.33364 | 0.00373 | 0.00020 | 1.00000 | |

# MidAmerican Energy Company
## Calculation of Load Factor

| (therms) | Total | Sales | Transport | Interdept Sales | Interdept Transport | Total Sales | Total Transport |
|---|---|---|---|---|---|---|---|
| 60 | 60,637,738 | 60,637,738 | - | - | - | 60,637,738 | - |
| 70 | 39,404,125 | 26,215,078 | 12,719,450 | 74,987 | 394,610 | 26,290,065 | 13,114,060 |
| 85 | 16,530,375 | 720,595 | 15,809,780 | - | - | 720,595 | 15,809,780 |
| 87 | 374,989 | 275,696 | 99,293 | - | - | 275,696 | 99,293 |
| Contract | 87,610,364 | - | 87,610,364 | - | - | - | 87,610,364 |
| Total Throughput | 204,557,591 | 87,849,107 | 116,238,887 | 74,987 | 394,610 | 87,924,094 | 116,633,497 |

| | | |
|---|---|---|
| Average Throughput | 558,901 | |
| All-time Peak | 1,143,026 | ML-9 attachment, page 14 |
| Load Factor | 48.897% | |

MidAmerican Energy Company
Functional Allocation Factors

| | | Peak Facilities | Mains (Average) | Mains (Peak) | Services | Meters | Regulators |
|---|---|---|---|---|---|---|---|
| 1 | Peaking Facilities | 1.0000000 | - | - | - | - | - |
| 2 | Average & Peak | - | 0.4889700 | 0.5110300 | - | - | - |
| 3 | Services | - | - | - | 1.0000000 | - | - |
| 4 | Meters | - | - | - | - | 1.0000000 | - |
| 5 | Regulators | - | - | - | - | - | 1.0000000 |
| 6 | Direct Assign - Non Residential Customers | - | - | - | - | - | - |
| 7 | Customer Accounts | - | - | - | - | - | - |
| 8 | COG | - | - | - | - | - | - |
| 9 | MGP Cleanup | - | - | - | - | - | - |
| 10 | Transportation Administration | - | - | - | - | - | - |
| 19 | Supervised O&M | 0.0337594 | 0.1122290 | 0.1172923 | 0.1611660 | 0.2573787 | 0.0300073 |
| 20 | Gross Production, Distribution Plant | 0.0429108 | 0.2660473 | 0.2780501 | 0.2899491 | 0.1014322 | 0.0195942 |
| 21 | Gross Plant | 0.0417841 | 0.2471088 | 0.2582572 | 0.2740929 | 0.1206328 | 0.0208763 |
| 22 | Net Plant | 0.0340223 | 0.2431455 | 0.2541151 | 0.2712946 | 0.1275220 | 0.0214354 |
| 23 | Gross Distribution Plant | - | 0.2779755 | 0.2905164 | 0.3029489 | 0.1059799 | 0.0204727 |
| 24 | Meters & Services Plant | - | - | - | 0.7408353 | 0.2591647 | - |
| 27 | Gross Mains and Services Plant | - | 0.3079848 | 0.3218797 | 0.3701355 | - | - |
| 28 | Gross Meters and Regulators Plant | - | - | - | - | 0.8381000 | 0.1619000 |
| 29 | Gross Plant Excluding Intangible | 0.0419087 | 0.2492040 | 0.2604469 | 0.2758471 | 0.1185086 | 0.0207344 |
| 30 | Distribution Operation Expense Less Supervision | - | 0.1712309 | 0.1789560 | 0.3721515 | 0.2421299 | 0.0350029 |
| 31 | Distribution Maintenance Expense Less Supervision | - | 0.2102706 | 0.2197570 | 0.1342896 | 0.3651458 | 0.0705370 |
| 32 | Cust Acct Expense Less Supervision | - | - | - | - | 0.2276883 | - |
| 33 | Payroll Allocator | 0.0307501 | 0.0971761 | 0.1015602 | 0.1715111 | 0.2666402 | 0.0268966 |
| 34 | Customer and A&G (excludes 923, 925, 926 and 931) | 0.015004 | 0.052414 | 0.054779 | 0.073751 | 0.244206 | 0.013165 |
| 35 | Weighted Injuries and Damages | 0.044841 | 0.139864 | 0.146174 | 0.257474 | 0.262038 | 0.039107 |

MidAmerican Energy Company
Functional Allocation Factors

| | | Industrial Meters | Customer Service | Transport Admin | COG | Total |
|---|---|---|---|---|---|---|
| 1 | Peaking Facilities | - | - | - | - | 1.0000000 |
| 2 | Average & Peak | - | - | - | - | 1.0000000 |
| 3 | Services | - | - | - | - | 1.0000000 |
| 4 | Meters | - | - | - | - | 1.0000000 |
| 5 | Regulators | - | - | - | - | 1.0000000 |
| 6 | Direct Assign - Non Residential Customers | 1.0000000 | - | - | - | 1.0000000 |
| 7 | Customer Accounts | - | 1.0000000 | - | - | 1.0000000 |
| 8 | COG | - | - | - | 1.0000000 | 1.0000000 |
| 9 | MGP Cleanup | - | - | - | - | - |
| 10 | Transportation Administration | - | - | 1.0000000 | - | 1.0000000 |
| 19 | Supervised O&M | 0.0001800 | 0.2511047 | 0.0088375 | 0.0280450 | 1.0000000 |
| 20 | Gross Production, Distribution Plant | 0.0020163 | - | - | - | 1.0000000 |
| 21 | Gross Plant | 0.0017902 | 0.0309167 | 0.0010881 | 0.0034530 | 1.0000000 |
| 22 | Net Plant | 0.0017339 | 0.0407463 | 0.0014341 | 0.0045508 | 1.0000000 |
| 23 | Gross Distribution Plant | 0.0021067 | - | - | - | 1.0000000 |
| 24 | Meters & Services Plant | - | - | - | - | 1.0000000 |
| 27 | Gross Mains and Services Plant | - | - | - | - | 1.0000000 |
| 28 | Gross Meters and Regulators Plant | - | - | - | - | 1.0000000 |
| 29 | Gross Plant Excluding Intangible | 0.0018152 | 0.0274964 | 0.0009677 | 0.0030710 | 1.0000000 |
| 30 | Distribution Operation Expense Less Supervision | 0.0005287 | - | - | - | 1.0000000 |
| 31 | Distribution Maintenance Expense Less Supervision | - | - | - | - | 1.0000000 |
| 32 | Cust Acct Expense Less Supervision | - | 0.7723117 | - | - | 1.0000000 |
| 33 | Payroll Allocator | 0.0001979 | 0.2566738 | 0.0118660 | 0.0367281 | 1.0000000 |
| 34 | Customer and A&G (excludes 923, 925, 926 and 931) | 0.000110 | 0.516394 | 0.018174 | 0.012002 | 1.0000000 |
| 35 | Weighted Injuries and Damages | 0.000296 | 0.050804 | 0.002349 | 0.057055 | 1.0000000 |